PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
DIABLO CANYON STEAM GENERATOR REPLACEMENT PROJECTS REPLACEMENT ENERGY COSTS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E or the Company) cost estimates for purchasing replacement energy or building replacement generation, as alternatives to the proposed Steam Generator Replacement Projects (the Projects). That is, if the steam generators in Units 1 and 2 of the Diablo Canyon Nuclear Power Plant (DCPP) are not replaced as proposed in this application, and DCPP's generation units are forced to shut down, PG&E will need to purchase power or build new generation to serve the energy needs of PG&E's bundled service customers.

Specifically, this chapter explains the derivation of the market price forecasts used by the cost/benefit analysis presented in Chapter 5, "Cost/Benefit Analysis of the Diablo Canyon Steam Generator Replacement Projects." In addition, this chapter compares the cost of power purchases at the projected market prices against conservative estimates of the cost of building or purchasing from new resource alternatives to the proposed replacement of the DCPP's steam generators at DCPP Units 1 and 2. PG&E uses conservative or low alternative cost estimates to test the robustness of the proposed Projects. Finally, this chapter examines the sensitivity of alternative power costs to the future price of natural gas.

This chapter updates PG&E's January 9, 2004 cost estimate of purchasing replacement energy or building replacement generation as alternatives to the Projects to account for two changes in assumptions regarding the operation of DCPP.[1] The two changes are: (1) an expected 20 MW increase in output from each of the DCPP units resulting from efficiency gains following replacement of the high and low pressure rotors for each Unit, and (2) the expectation of an approximate three-year extension to the operating license of DCPP Unit 1, from

[1] PG&E's initial estimate of the costs of purchasing replacement energy or building replacement generation as alternatives to the Projects was presented in Chapter 6 of its original testimony dated January 9, 2004.

September 21, 2021, to November 2, 2024. PG&E's original alternative energy cost estimate assumed the DCPP output would be 1100 MW per unit, and that DCPP Unit 1 would operate only until the end of its existing license life in 2021.

The tables and figure included in this testimony have been updated to reflect these two changes in assumptions.

This chapter is organized as follows:

- Section B—Summary of Results;
- Section C—Resource Alternatives Considered;
- Section D— Market Price Scenario;
- Section E— Combined Cycle Generation Cost Scenario;
- Section F— Combined Cycle and Renewable Generation Cost Scenario;
- Section G— Other Risks and Costs Associated with the Alternative Generation Scenarios; and
- Section H—Summary of the Alternative Cost Scenarios.

B. Summary of Results

The total cost of replacement energy, if the Projects are not pursued, is summarized below:

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE ALTERNATIVE RESOURCE COSTS
2003 PRESENT VALUE ($MILLION)

Line No.		Market purchases	Combined cycle (CC) generation ("100% CC")	90% CC plus 10% MW renewable generation
1	2003 PV	$3,120	$3,122	$3,107

As explained below for each of the generation alternatives, PG&E uses conservative assumptions that result in low alternative costs to test the robustness of the proposed Projects. In order to avoid getting into a debate about the most likely cost of new generation alternatives, PG&E relies on the California Energy Commission's (CEC) cost estimates of new generation technologies.[2] PG&E believes the CEC's estimates represent a low or optimistic view of the cost of new generation alternatives. However, as discussed in Chapter 5, even these low alternative costs significantly exceed the cost of the Projects by over $1.38 billion, making the Projects the preferred alternative.

C. Resource Alternatives Considered

In order to estimate the Projects' value, PG&E estimated the costs of replacement power under a broad range of scenarios.

1. Market Price Scenario

Under this alternative, PG&E would purchase power at forecast market prices from the dates when each of the DCPP Units 1 and 2 are shut down until the end of the license life. Without the Projects, the Diablo Canyon units are expected to shut down on the following dates:

- Unit 1: February 2, 2014; and
- Unit 2: February 3, 2013.

This alternative assumes that sufficient replacement power will be available to purchase 1,120 MW for Unit 1 and 1,120 MW for Unit 2 (the output of each Unit is expected to increase following the completion of the low pressure rotor replacement in 2006) in the marketplace. For purposes of estimating PG&E's alternative market purchase costs, PG&E has conservatively assumed that 2,200 MW of new merchant combined cycle generation will be added by the WECC market participants in anticipation of meeting demand growth and the forecasted shutdown of DCPP available when needed.[3] These market prices are those that were used throughout the cost-benefit analysis described in Chapter 5.

In Section G, PG&E assumes that new combined cycle generation is not available in time to replace DCPP's generation. The assumption that new combined cycle generation will be available when needed (rather than

[2] CEC Staff report dated August 2003 titled "Comparative Cost of California Central Station Electricity Generation Technologies".

[3] The additional 40 MW (the difference between DCPP's expected 2,240 MW output and the 2,200 MW of assumed new combined cycle generation) is assumed to come from existing or otherwise already planned resource additions.

constructed after the need becomes known when Units 1 and 2 are shut down) is conservative because it reduces the Projects' alternative cost.

2. Combined Cycle Generation Cost Scenario

Under this alternative, PG&E contracts or builds 2200 MW[4] of new combined cycle generation to be on-line by the date when the DCPP Units 1 and 2 are expected to be shut down if the Projects are not implemented. This alternative uses the CEC's construction cost assumptions for combined cycle generation. This alternative also assumes conservatively that such combined cycle generation is available immediately upon shutdown of Units 1 and 2, and is not available for operation before or after such replacement power is needed.

3. Combined Cycle and Renewable Generation Cost Scenario

Under this alternative, PG&E substitutes part of the new combined cycle generation in Alternative 2 with renewable generation when the DCPP Units 1 and 2 are shut down. PG&E provides a discussion of the incremental cost of renewable generation, relative to combined cycle generation, for wind, geothermal and solar renewable technologies. PG&E uses the CEC's renewable generation cost assumptions. This alternative also assumes conservatively that both combined cycle and renewable generation are available immediately upon shutdown of Units 1 and 2, and are not available before or after such replacement power is needed.

D. Market Price Scenario

Under this alternative, PG&E purchases power at forecast market prices from the expected dates when each of DCPP's Units 1 and 2 would be shut down if the steam generators are not replaced (Unit 1 on February 2, 2014, and Unit 2 on February 3, 2013) until the end of their expected license life.

1. Market Price Forecast

PG&E derives its market price forecast through MARKETSYM simulations using Henwood's Fall 2003 Western Electricity Coordinating

[4] The additional 40 MW is assumed to be purchased from the market and the costs of doing so are included as a portion of the "operating costs" in Table 6-5.

Council (WECC) Reference Case, based on natural gas prices projected by PG&E.

PG&E uses scenario analysis to depict a plausible range of energy market prices by varying the natural gas prices used in the MARKETSYM simulations. The base case uses commodity gas prices based on the September 5, 2003, closing price of forward contracts traded in the New York Mercantile Exchange (NYMEX), plus location basis obtained from broker quotes for gas delivered at Topock, Malin and PG&E Citygate. Beyond 2008, PG&E extrapolates gas prices using the 1.1 percent rate, which corresponds to the escalation of the closing prices of the NYMEX natural gas forward contracts between 2006 and 2008.[5] The high case assumes natural gas prices are 40 percent higher than in the base case. The low case assumes natural gas prices are 40 percent lower than in the base case.

Table 6-2 provides the expected annual Northern California burner tip gas prices for years 2008 through 2027 for the three scenarios used.

[5] Escalation is calculated based on the September 5, 2003 closing prices of the NYMEX natural gas forward contracts between 2006 and 2008, the last three years of forward prices available in NYMEX.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL AVERAGE GAS PRICES, $/MMBTU

Line No.	Year	Base	High	Low
1	2008	$5.22	$7.31	$3.13
2	2009	$5.28	$7.39	$3.17
3	2010	$5.34	$7.48	$3.21
4	2011	$5.41	$7.57	$3.25
5	2012	$5.47	$7.66	$3.28
6	2013	$5.54	$7.76	$3.32
7	2014	$5.61	$7.85	$3.36
8	2015	$5.67	$7.94	$3.40
9	2016	$5.74	$8.04	$3.45
10	2017	$5.81	$8.14	$3.49
11	2018	$5.88	$8.23	$3.53
12	2019	$5.95	$8.33	$3.57
13	2020	$6.02	$8.43	$3.61
14	2021	$6.10	$8.53	$3.66
15	2022	$6.17	$8.64	$3.70
16	2023	$6.24	$8.74	$3.75
17	2024	$6.32	$8.85	$3.79
18	2025	$6.39	$8.95	$3.84
19	2026	$6.47	$9.06	$3.88
20	2027	$6.55	$9.17	$3.93

The resulting replacement energy prices for the scenario where there is capacity in the market available to meet the new 2,240 MW of demand resulting from shutdown of DCPP Units 1 and 2 is set forth in Table 6-3 below:

TABLE 6-3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL AVERAGE NP15 7X24 ENERGY PRICES, $/MWH

Line No.	Year	Base	High	Low
1	2008	42.65	56.74	32.93
2	2009	45.58	60.64	35.00
3	2010	49.23	65.26	37.88
4	2011	51.87	68.63	39.93
5	2012	53.59	71.02	41.20
6	2013	55.35	73.37	42.57
7	2014	56.62	75.00	43.58
8	2015	57.69	76.42	44.33
9	2016	58.78	77.85	45.12
10	2017	59.80	79.25	46.00
11	2018	60.56	80.25	46.60
12	2019	61.33	81.26	47.21
13	2020	62.12	82.29	47.83
14	2021	62.91	83.33	48.46
15	2022	63.71	84.38	49.09
16	2023	64.48	85.35	49.72
17	2024	65.25	86.33	50.36
18	2025	66.03	87.32	51.00
19	2026	66.83	88.32	51.65
20	2027	67.63	89.33	52.31

2. Resulting Market Purchase Costs

The resulting replacement energy purchase costs for the scenario where there is capacity in the market available to meet the new 2,240 MW of demand resulting from shutdown of DCPP Units 1 and 2 is set forth in Table 6-4 below. Note that the average annual replacement purchase cost in Table 6-4 differs from the average 24-hour price in Northern California of Table 6-3 because the average replacement annual cost accounts for the DCPP generation pattern.

TABLE 6-4
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE MARKET PURCHASE COST

Line No.	Year	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$427,747	7676	55.7
2	2014	$921,584	16192	56.9
3	2015	$1,011,434	17510	57.8
4	2016	$1,033,322	17559	58.8
5	2017	$1,048,635	17512	59.9
6	2018	$1,062,934	17507	60.7
7	2019	$1,045,460	16982	61.6
8	2020	$1,091,970	17562	62.2
9	2021	$1,101,668	17542	62.8
10	2022	$1,117,243	17553	63.6
11	2023	$1,132,264	17569	64.4
12	2024	$1,043,929	16061	65.0
13	2025	$174,980	2843	61.5
14	2026	NA	NA	NA
15	2027	NA	NA	NA
16	2028	NA	NA	NA
17	2029	NA	NA	NA
18	2003 PV	$3,120,067	NA	60.3

E. Combined Cycle Generation Cost Scenario

The second scenario was one where PG&E contracts or builds 2200 MW of new combined cycle generation to be on-line by the date when the DCPP Units 1 and 2 are expected to be shut down. The cost of new combined cycle generation has two major components: (1) fixed capital-related and fixed operations and maintenance (O&M)-related costs, (2) and operating costs.

1. Fixed Capital-related Costs

Fixed capital costs are associated with siting, permitting, financing and building new generation, including the cost of gas and electricity infrastructure for the new generation. PG&E relies on the CEC's combined cycle construction cost estimate. The CEC's estimate is low because it includes no interconnection or transmission network upgrade costs.

Consistent with current Federal Energy Commission (FERC) policy, a power plant developer is responsible for system interconnection costs, including direct assignment facilities (or generation tie) costs, which are needed to connect the resource to the network.

Fixed costs also include network upgrades, which are facilities that may be needed to accommodate the generation beyond the generation tie's connection to the network. Network upgrade facilities include transmission lines, transformer banks, special protection systems, substation breakers and other equipment that is needed to transfer power to the consumers. Because network upgrades are not used exclusively by the new generation, electric consumers ultimately pay the costs of these facilities through transmission rates. Being borne ultimately by consumers, network upgrade costs must be included as part of the cost of alternative generation.[6]

Fixed costs also include fixed O&M costs such as wages and salaries of full time staff, insurance costs, and property costs, etc.

2. Operating Costs

Operating costs include the cost of fuel and other supplies used by the new combined cycle units, as well as the variable O&M costs. Combined cycle plants are generally considered baseload generation that closely resembles the generation pattern of the DCPP Units. However, because PG&E is assumed to contract or build 2,200 MW of new combined cycle generation, rather than the expected 2,240 MW output of the DCPP Units, and because of the different operating characteristics of DCPP and the combined cycle units, such as different forced outage rates and planned outage schedules, the volume of generation from the combined cycle units may at times differ from that of the DCPP Units. These differences in generation are valued at the forecast energy prices, and are included as part of operating costs. For example, if at a given time, the combined cycle units produce less energy than the DCPP Units, that additional generation is “purchased” at forecast energy prices. In addition, a new combined cycle generating plant built to replace DCPP generation will have a life that extends beyond the date when replacement energy would be needed even with steam generator replacement (i.e., the expected license life of DCPP Units 1 and 2).

In this analysis, the capital cost of new combined cycle generation is levelized over its expected life. The combined cycle capital cost and its fixed and variable operating costs through 2029 are included in estimating this

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[6] Under current FERC policy, the utility has the option to require the developer to fund the network upgrades and be repaid, with interest, after the new generation is operational.

alternative's costs. Beyond 2029, the difference between the Project's continuing costs and the value of its generation is assumed to be approximately equal and therefore not considered.

For purposes of analyzing the Projects, PG&E has assumed that with the steam generators replacement the DCPP Units will retire at the end of the expected license life for each Unit.[7]

3. Resulting Alternative Combined Cycle Costs

Table 6-5 summarizes the alternative combined cycle generation cost both in $ per year and $/MWh. The cost reflects replacement of power from both Units 1 and 2 as of the dates that each is expected to be shut down through its expected license termination.

TABLE 6-5
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE COMBINED CYCLE COST

Line No.	Year	Fixed capital & O&M cost, $000	Operating costs, $000	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$108,616	$330,732	$439,349	7676	57.2
2	2014	$229,682	$707,990	$937,672	16192	57.9
3	2015	$240,893	$782,348	$1,023,241	17510	58.4
4	2016	$242,077	$794,823	$1,036,899	17559	59.1
5	2017	$243,290	$803,350	$1,046,640	17512	59.8
6	2018	$244,533	$815,656	$1,060,189	17507	60.6
7	2019	$245,808	$796,030	$1,041,837	16982	61.3
8	2020	$247,114	$840,228	$1,087,343	17562	61.9
9	2021	$248,453	$847,457	$1,095,910	17542	62.5
10	2022	$249,826	$860,405	$1,110,230	17553	63.3
11	2023	$251,232	$874,357	$1,125,589	17569	64.1
12	2024	$252,674	$784,806	$1,037,480	16061	64.6
13	2025	$254,152	$(85,504)	$168,649	2843	59.3
14	2026	$255,667	$(261,990)	$(6,322)	NA	NA
15	2027	$257,220	$(263,641)	$(6,421)	NA	NA
16	2028	$257,220	$(270,233)	$(13,012)	NA	NA
17	2029	$257,220	$(276,988)	$(19,768)	NA	NA
18	2003 PV	$889,507	$2,232,064	$3,121,571	NA	60.3

F. Combined Cycle and Renewable Generation Cost Scenario

In this scenario, PG&E substitutes 10 percent of new combined cycle generation in Scenario 2 (described above) with renewable generation when the

[7] Unit 1's license is expected to be extended and then expire on November 2, 2024, and Unit 2's expires on April 26, 2025.

DCPP Units 1 and 2 are shut down. Renewable resources are primarily provided by wind, geothermal and solar renewable technologies. Because renewable generation does not have a similar level of reliability or delivery profile as DCPP or generic combined-cycle resources, PG&E does not estimate the impact of replacing all of DCPP's generation with renewable resources. Instead, PG&E estimates in this section the alternative replacement power cost when substituting 10 percent of combined cycle generation with an equivalent energy amount of renewable resources. The CEC Staff generation technologies report was used as a reference for the cost of renewables. That report suggests that solar energy is much more costly than either wind or geothermal, so solar was not reflected in this analysis. Geothermal generation may be cost-competitive with wind depending on whether it is "flash" or "binary" technology. Because of questions about the quantity of geothermal "flash" technology sites in California, this analysis focuses on wind energy as the renewable resource to be analyzed.

1. Wind Costs

This analysis adopts the cost of the wind farms as published in the above-referenced CEC report. In this analysis the DCPP generation replacement is 17,660 GWh (approximately a 90 percent capacity factor) of which 1732 GWh is from wind generation. At the 40.2 percent capacity factor assumed by the CEC for wind, there is a need for 492 MW of installed wind capacity.[8] The remaining energy needs are assumed to come from combined cycle generation and market purchases. Based on a 90 percent availability factor (5 percent for forced outages and 5 percent for maintenance outages), 1977 MW is from installed combined cycle generation.[9] Therefore, there would be a need to have 1977 MW of combined cycle generation, 492 MW of wind capacity, and a small amount of market purchases to replace the DCPP generation.

While PG&E has used the CEC's August 2003 wind cost estimates for purposes of its cost-effectiveness analysis in this testimony, PG&E does have a few reservations about these estimates and believes they understate

[8] Ten Percent of 17,320 GWh per year divided by 8,760 hours at a 40.2 percent capacity factor.

[9] 90 percent of 17,320 GWh per year divided by 8,760 hours and a 90 percent capacity factor.

the costs of wind generation. We list these reservations in order to preserve PG&E's position but it is not necessary to address these issues in this proceeding given the robust cost-effectiveness showing that results using the CEC estimates without adjustment. First, the CEC report assumes a wind capacity factor of 40.2 percent. Data collected by the CEC suggests that an assumption of 30 to 35 percent annual capacity factor for new wind turbines is a more reasonable assumption. Second, given the intermittent nature of wind, replacement costs are higher because of the need to firm up wind generation to achieve the same level of dependable capacity as the other alternatives. Finally, as indicated before, the CEC did not include the cost of transmission lines and substations.

As with the prior alternative, new combined cycle generating plant and wind farms built to replace DCPP generation have lives that extend beyond the expiration of the Nuclear Regulatory Commission (NRC) licenses for DCPP Units 1 and 2. In this analysis, the capital cost of new combined cycle generation and the wind farm is levelized over their respective lives, and the energy produced by the combined cycle/wind generation is credited against project cost through 2029. Beyond 2029, the differences between the combined cycle/wind project continuing costs and the value of such generation are assumed to be approximately equal and therefore not considered.

2. Resulting Alternative Renewable Costs

Table 6-6 summarizes the alternative renewable generation cost for wind, both in $ per year and $/MWh. The cost reflects replacement of 10 percent of power from each Unit 1 and 2 from the dates the units are shut down through the year 2029, with energy credits given for the period after the end of license of each DCPP Unit.

TABLE 6-6
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE 90% CC AND 10% RENEWABLE COST

Line No.	Year	CC costs, (includes balancing cost) $000	Renewable costs, $000	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$390,086	$48,125	$438,211	7,676	57.1
2	2014	$837,013	$97,980	$934,993	16,192	57.7
3	2015	$920,248	$99,751	$1,019,999	17,510	58.3
4	2016	$932,374	$100,778	$1,033,151	17,559	58.8
5	2017	$940,973	$101,830	$1,042,802	17,512	59.5
6	2018	$953,337	$102,908	$1,056,246	17,507	60.3
7	2019	$933,797	$104,014	$1,037,811	16,982	61.1
8	2020	$978,111	$105,147	$1,083,258	17,562	61.7
9	2021	$985,483	$106,308	$1,091,791	17,542	62.2
10	2022	$998,603	$107,499	$1,106,102	17,553	63.0
11	2023	$1,012,553	$108,719	$1,121,272	17,569	63.8
12	2024	$923,027	$109,970	$1,032,997	16,061	64.3
13	2025	$52,772	$111,252	$164,024	2,843	57.7
14	2026	$(123,631)	$112,566	$(11,065)	NA	NA
15	2027	$(125,170)	$113,913	$(11,257)	NA	NA
16	2028	$(134,087)	$115,294	$(18,793)	NA	NA
17	2029	$(143,226)	$116,709	$(26,517)	NA	NA
18	2003 PV	$2,726,363	$380,868	$3,107,231	NA	60.1

G. Other Risks and Costs Associated with the Alternative Generation Scenarios

1. Additional Replacement Costs and Risks

In the event that the Projects are not implemented, there would be uncertainty as to: (1) the exact time when the Diablo Canyon units may need to be shut down, and (2) the increased probability of extended forced outages as explained in Chapter 5. These uncertainties would translate into an unknown schedule for building or contracting to purchase replacement generation, and ultimately into the possibility of higher than anticipated replacement power costs, and adverse reliability impacts if not enough resources are available in the market to replace a DCPP unit forced to shut down. If, for example, one of the two Units must shut down before new generation is built or contracted by PG&E, there would be an increase in market prices paid by PG&E to meet its open position.

Conversely, if the DCPP Units continue to operate beyond their expected shutdown dates, and new generation is built or purchased for operation before those dates, customers would be exposed to paying for replacement generation that may not be needed and that may need to be sold at less than cost as surplus sales.

In Table 6-7, PG&E provides an estimate for years 2013 through 2016 of the additional cost of purchasing from the market if replacement generation is not built by the time the DCPP Units are shut down, relative to the market purchase estimate presented in Section C. To prepare this estimate, PG&E forecasted market prices via MARKETSYM simulations excluding the DCPP Units and replacement combined cycle generation.

TABLE 6-7
PACIFIC GAS AND ELECTRIC COMPANY
INCREASE IN REPLACEMENT COSTS DUE TO RISK OF EXTENDED OUTAGES OR EARLY SHUTDOWN OF THE NUCLEAR UNITS, $000

Line No.	Year	$000
1	2013	$9,124
2	2014	$36,297
3	2015	$37,291
4	2016	$38,775

2. Increased Emissions

If the DCPP Units are shut down and generation is replaced with gas-fired combined cycle generation, one would expect there to be increases in air emissions in California and the WECC system. Since natural gas is a fairly clean-burning fuel, there would be little increase in sulfur dioxide (SOx) or nitrous oxide (NOx) emissions on a WECC-wide level, although local air sheds may show meaningful impacts. WECC wide, carbon dioxide (CO2) emissions are expected to increase significantly. Annual differences in CO2 emissions (in thousands of tons) between DCPP generation and combined cycle generation is shown in Table 6-8 below.

TABLE 6-8
PACIFIC GAS AND ELECTRIC COMPANY
WECC-WIDE CO2 EMISSIONS IF DCPP GENERATION IS REPLACED WITH COMBINED CYCLE COMBUSTION TURBINE GENERATION (THOUSAND OF TONS)

Line No.	Year	WECC-wide CO2 Emissions With Diablo ktons	WECC-wide CO2 Emissions Without Diablo ktons	Difference ktons
1	2013	470,867	477,938	7,071
2	2014	479,135	486,541	7,406
3	2015	486,690	494,074	7,384
4	2016	495,719	503,102	7,383
5	2017	504,521	511,150	6,630
6	2018	513,069	519,766	6,697
7	2019	521,762	528,528	6,765
8	2020	530,603	537,437	6,834
9	2021	539,594	546,496	6,902
10	2022	548,737	555,709	6,971
11	2023	558,372	565,331	6,959
12	2024	568,150	575,120	6,971
13	2025	578,100	585,080	6,981
14	2026	588,225	595,214	6,989
15	2027	598,529	605,525	6,995
16	Total			104,938

H. Summary of the Alternative Cost Scenarios

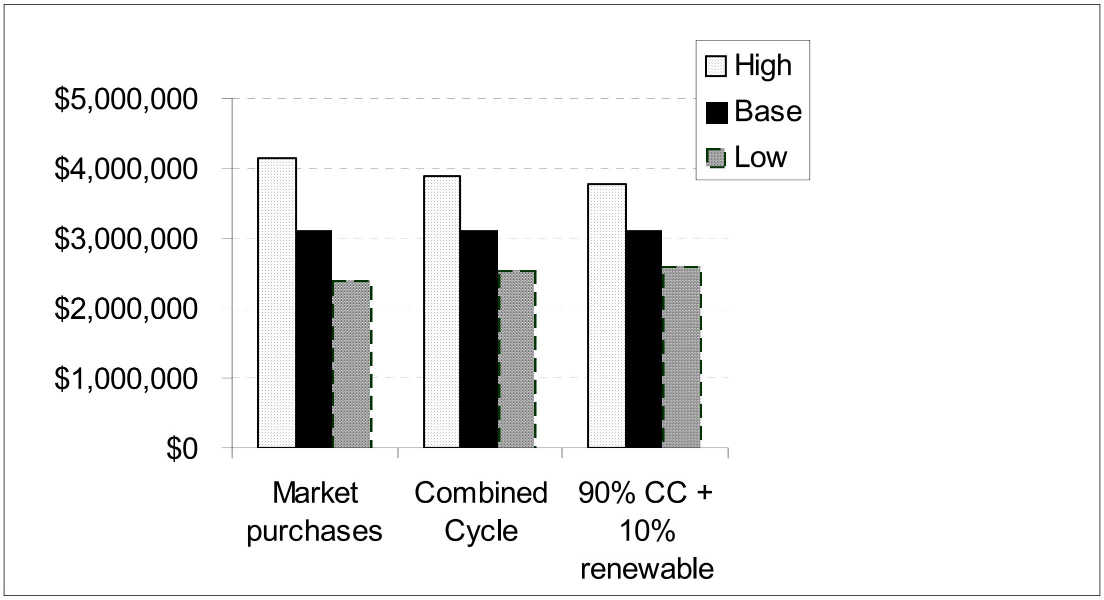
Table 6-9 compares the alternative demand/supply costs based on the assumptions set forth above:

TABLE 6-9
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE RESOURCE COSTS, $000

Line No.	Year	Market purchases	Combined cycle generation (“100% CC”)	90% CC plus 10% MW renewable generation
1	2003 PV	$3,120,067	$3,121,571	$3,107,231

Figures 6-1 summarizes the cost of alternative resources under various natural gas price assumptions:

FIGURE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
COST SENSITIVITY TO GAS PRICES



As shown in Table 6-9 and Figure 6-1, all the generation alternatives considered have costs that are similar if not higher than the estimated cost of purchasing power to replace DCPP at the projected market prices. As expected, market purchase costs show the greatest sensitivity to natural gas price uncertainty. Therefore, for purposes of analyzing the robustness of the proposed Projects it is reasonable to use the range of market price forecasts presented in Section D of this chapter.